DRAFT INSPECTION REPORT
SHELL PUGET SOUND REFINERY
CAA Section 112(r) and RCRA

Stationary Source	Shell Puget Sound Refinery
Date of Inspection	August 10-13, 2015
USEPA Contact	Javier Morales, EPA Region 10, 206-553-1255
Description of Activities	Formal Information Request dated March 19, 2015 under CAA 114 authorities; Notice of Inspection dated July 13, 2015; Opening meeting with Shell Puget Sound representatives on August 10, 2015; Investigation consisting of the following activities: - Credentials presentation and opening conference - Document review - Field verification - Personnel interviews - Closing meeting with Shell Puget Sound representatives - During the inspection additional written information requests were presented to Shell Puget Sound Refinery under the authority of CAA 114
Investigation Participants	August 10-13: Trent Rainey, EPA NEIC, Lead Investigator; Linda TeKrony, EPA NEIC, Investigator; Jackie Vega, EPA NEIC, Investigator; Javier Morales, EPA Region 10, Investigator; Jon Jones, EPA Region 10, Investigator; Craig Haas, EPA Headquarters OECA\WCED, Investigator; Anthony Gaglione, Eastern Research Group, Inc., Contractor, Technical Expert Support.

Stationary Source Information

USEPA Facility ID #	1000 0009 9252
Most Recent Submission	Date – April 22, 2015 Anniversary Date – April 22, 2020
Facility Contact	Adam Filby, Business Improvement Plan Coordinator, adam.filby@shell.com and Brian Ricks, USW Process Safety Management Representative, Brian.Ricks@shell.com
Facility Location	8505 South Texas Road Anacortes, WA 98221 Skagit County
Lat / Long	48.478917 / -122.570861
Number of Employees	455 (Full-time employees)
Description of Surrounding Area	The Shell Puget Sound Refinery (PSR) is located on March Point within the Puget Sound, Washington. March Point is a peninsula, surrounded by the Fidalgo Bay to the west and north and the Padilla Bay to the east and north. The City of Anacortes is west of the refinery. The Tesoro Anacortes Refinery is adjacent to the north side of the Shell PSR. The Swinomish Indian Tribal Community is southeast of the Shell PSR. The Shell PSR RMP OCA indicates a rural topography. The toxics WCS, which results in the largest distance to endpoint, reports a 1.5-mile distance to endpoint and indicates an impacted residential population of 440 and public recreation and commercial/industrial endpoints. The Fidalgo Bay Aquatic Reserve is due west of the facility in the Fidalgo Bay.

RMP Submittal

The Facility's initial RMP submittal date was June 21, 1999. The latest RMP submittal at the time of the inspection was April 22, 2015. The next RMP submittal anniversary due date is April 22, 2020.

Covered Processes:

Process ID	Process Chemical ID	Process Name	Program Level	Chemical Name	CAS Number	Quantity (lb)
1000062338	1000076789	Alkylation Unit #1	3	Isobutane	75-28-5	330,000
	1000076790			Butane	106-97-8	51,000
	1000076788			Propane	74-98-6	21,000
	1000076791			Isopentane	78-78-4	18,000
	1000076917			2-Butene-trans	624-64-6	13,000
	1000076916			2-Butene-cis	590-18-1	10,000
1000062344	1000076831	Alkylation Unit #2	3	Isobutane	75-28-5	650,000
	1000076832			Butane	106-97-8	150,000
	1000076834			Isopentane	78-78-4	25,000
	1000076828			Propane	74-98-6	18,000

Process ID	Process Chemical ID	Process Name	Program Level	Chemical Name	CAS Number	Quantity (lb)
1000062348	1000076858	Boiler House / Cogeneration	3	Ammonia (anhydrous)	7664-41-7	91,000
1000062342	1000076817	Catalytic Reformer #1	3	Isopentane	78-78-4	17,000
1000062343	1000076824	Catalytic Reformer #2	3	Isobutane	75-28-5	26,000
	1000076825			Butane	106-97-8	24,000
	1000076822			Propane	74-98-6	21,000
	1000076826			Isopentane	78-78-4	11,000
1000062420	1000076950	Crude Distillation Unit	3	Butane	106-97-8	8,000
1000062421	1000076951	Delayed Coking Unit	3	Butane	106-97-8	4,200
1000062345	1000076840	FCCU / GRU	3	Propylene	115-07-1	19,000
	1000076841			Isobutane	75-28-5	15,000
	1000076924			Isopentane	78-78-4	12,000
1000062340	1000076801	Hydrotreating Unit #1	3	Pentane	109-66-0	20,000
	1000076799			Butane	106-97-8	15,000
	1000076800			Isopentane	78-78-4	13,000
1000062341	1000076807	Hydrotreating Unit #2	3	Butane	106-97-8	35,000
	1000076809			Pentane	109-66-0	10,000
1000062347	1000076926	Hydrotreating Unit #3	3	Isopentane	78-78-4	12,000
1000062346	1000076847	Poly	3	Propane	74-98-6	230,000
	1000076848			Propylene	115-07-1	69,000
	1000076850			Butane	106-97-8	53,000
	1000076849			Isobutane	75-28-5	45,000
1000062339	1000076793	Railcar Loading Rack	3	Butane	106-97-8	3,900,000
	1000076919			Isobutane	75-28-5	2,300,000
	1000076918			Propane	74-98-6	820,000
	1000076921			Propylene	115-07-1	50,000
	1000076920			Isopentane	78-78-4	48,000
1000062335	1000076762	Tank Farm	3	Butane	106-97-8	8,500,000

Process ID	Process Chemical ID	Process Name	Program Level	Chemical Name	CAS Number	Quantity (lb)
	1000076763			Isopentane	78-78-4	7,600,000
	1000076759			Isobutane	75-28-5	4,200,000
	1000076862			Pentane	109-66-0	4,000,000
	1000076758			Propane	74-98-6	1,300,000
	1000076859			2-Butene-cis	590-18-1	240,000
	1000076764			Propylene	115-07-1	180,000
	1000076860			2-Butene-trans	624-64-6	170,000
	1000076760			1-Butene	106-98-9	170,000
	1000076861			2-Methylpropene	115-11-7	150,000
	1000076863			Ethane	74-84-0	47,000

GENERAL INFORMATION AND PURPOSE:

EPA Region 10 requested the EPA National Enforcement Investigations Center (NEIC) to conduct a multimedia compliance investigation of the Shell Oil Products U.S. (Shell) Puget Sound Refinery (PSR). The scope of the EPA inspection was to evaluate the facility's compliance with the Clean Air Act (CAA) Section 112(r) Risk Management Program and the Resource Conservation and Recovery Act (RCRA).

During the inspection, representatives of the Shell United Steel Workers (USW) union were present each day. Employee representatives were encouraged to particulate in all meetings, interviews, and discussions, and were available for employee interviews as requested by the EPA investigators.

Three facility tours were conducted during the inspection. The first was a driving tour of the refinery on the first day of the inspection (August 10, 2015). The second tour conducted a P&ID field verification of the ammonia tank (90-C009), HTU #2, and one of the butane spheres (TK-102); field visit to the flares and FGR on August 12, 2015. The last tour visited a degassing unit (5JC-94) in the Poly Unit and the spent acid tanks for Alky 1 and Alky 2, based on an employee complaint of hydrocarbon emissions, on August 13, 2015.

This report documents the findings of the EPA inspection. The following narrative includes a general description of the facility and identifies EPA findings with respect to CAA Section 112(r) regulatory provisions.

FACILITY DESCRIPTION

The Shell PSR is located on March Point in the Puget Sound, adjacent to the city of Anacortes and within Skagit County, Washington. The Shell PSR was built in 1958 by Texaco (and Shell built the current Tesoro Anacortes refinery in 1955). In 1998, the Shell-Texaco joint venture Equilon divested the Shell facility to Tesoro. In 2002, Shell bought Texaco's interest in Equilon. The Shell PSR is currently owned and operated by Shell Oil Products, Inc.

The facility had a major expansion in 1975, adding a hydrotreating unit (HTU), catalytic reforming unit (CRU), and alkylation unit (Alky). In 2010, Shell completed their Benzene Reduction Project and purchased the March Point Cogen.

The Shell PSR has a capacity of 145,000 barrels per day (bpd) of crude oil. Much of Shell PSR's feedstock comes from the Alaska North Slope via tanker. The refinery also receives crude from Central and Western Canada via pipeline. The refinery produces three grades of gasoline; fuel oil; diesel fuel; propane; butane; petroleum coke; nonene; and C12 tetramer.

The Shell PSR distills crude feed through its crude distillation unit (the vacuum pipe still, VPS), which consists of an atmospheric tower, a gas oil tower, and a vacuum tower, which operate in series. Diesel and straight-run naphtha are hydrotreated in HTU #2. Jet fuel, and some naphtha, are hydrotreated in HTU #1. Vacuum residuum is processed in the delayed coking unit (DCU) to produce petroleum coke, gas oils, naphtha, and fuel gas. The DCU has two drums operating on a 16-24 hour cycle time. The produced coke is trucked and railed to the Port of Anacortes, where it is transported to customers via barge and ship. Atmospheric and vacuum (VPS) gas oils are processed through the fluid catalytic cracking unit (FCCU). FCCU gasoline (the bottoms of the debutanizer column) are hydrotreated in HTU #3. Some light naphtha is isomerized in the isomerization unit (ISOM) to produce isomerate. HTU #1 and #2 naphtha are sent to a decyclohexanizer (DCH), and the DCH bottoms are sent to the catalytic reformers CRU #1 and #2.

The Shell PSR has a boiler house (BOHO) and cogeneration (cogen) unit for producing electricity. The BOHO produces 600 psig steam (approximately 250,000 lb/hr) and there are three cogen units that each produce 45 MW of electricity. The electricity produced is entirely exported to the grid. The Shell PSR's electricity use is entirely from the grid.

The refinery has two sulfur plants with redundant capacity. Sulfur is trucked to a local customer. The refinery has three flares on a common header: a north, south, and east flare. The flares share a single flare gas recovery unit (FGR). The east flare is the preferential flare. If the relieving capacity of the east flare is exceeded, the relieving materials then relieve to the north and south flare. The seal pressure in each flare's seal pot is used to determine relieving preference. The flares are not RMP-covered processes. The refinery includes within the flare boundary, the three flares, the FGR, and the amine absorbers.

The Shell PSR has a Poly unit that reacts propylene to produce C6, C9, and C12. After the reaction products are depropanized and debutanized, the bottoms are sent to the Nonene unit to be fractionated into a gasoline product, a nonene (C9) chemical product, and a tetramer (mostly C12) chemical product.

RMP DOCUMENTATION AND FINDINGS

RMP Submittal

The Facility has a written Risk Management Plan. The first RMP was submitted on June 21, 1999. The most current RMP at the date of the inspection was submitted on April 22, 2015.

Each reviewed RMP element is discussed below.

MANAGEMENT SYSTEM: 40 CFR §§ 68.12 – 68.15

This RMP element was not reviewed.

APPLICABILITY AND THRESHOLD DETERMINATION: 40 CFR § 68.10 AND § 68.115 [NEIC]

ERG did not evaluate this RMP element.

HAZARD ASSESSMENT: 40 CFR § 68.20-68.42

Shell PSR included in their RMP submission a worst-case release scenario (WCS) and alternative release scenario (ARS) offsite consequence analysis (OCA) for toxics and flammables. Shell PSR provided the inspection team with background documentation used in their OCA (PSR05811-PSR05816 and PSR05843-PSR05878).

Toxics OCA

The toxics OCA was performed for anhydrous ammonia released from the ammonia storage tank in the Boiler House/Cogeneration RMP-covered process. Shell PSR reports a WCS radius of 1.5 miles in their RMP submission, calculated using the U.S. Coast Guard's model Dense Gas Dispersion (DEGADIS). Shell PSR determined receptors of residences, public recreational areas, and major commercial, office, or industrial areas. Shell PSR calculated an estimated residential population within the WCS radius of 440. However, the inspection team used RMP*Comp and calculated a distance to endpoint radius of 5.4 miles. Using Marplot, the inspection team estimated a residential population of 20,318. Since Shell PSR's estimate is significantly less than RMP*Comp's estimate, further documentation from Shell PSR on their use of DEGADIS for ammonia air dispersion modeling is needed to confirm that Shell PSR complied with 40 CFR § 68.25(g). Shell PSR's background documentation (PSR05811-PSR05816 and PSR05843-PSR05878) does not document the details of the DEGADIS modeling. 40 CFR § 68.25(g) requires that: "The owner or operator shall use the parameters defined in § 68.22 to determine distance to the endpoints. The owner or operator may use the methodology provided in the RMP Offsite Consequence Analysis Guidance or any commercially or publicly available air dispersion modeling techniques, provided the techniques account for the modeling conditions and are recognized by industry as applicable as part of current practices."

Shell PSR reports a toxics ARS radius of 0.84 miles in their RMP submission, identified residences, public recreational areas, and major commercial, office, or industrial areas as receptors. They estimated a residential population of 65. Using the release rate and duration provided by Shell PSR, and using RMP*Comp and Marplot, the inspection team calculated radius of 0.6 miles and a residential population of 96. The inspection team would need additional documentation from Shell PSR to confirm their correct use of DEGADIS in modeling the toxics ARS OCA.

Flammables OCA

The flammables OCA was performed for a vapor cloud explosion (both WCS and ARS) for a butane sphere in the Tank Farm RMP-covered process. Shell PSR used the EPA OCA Guidance Reference Tables or Equations to calculate their flammables WCS and ARS OCA. Shell PSR calculated a WCS radius of 1.07 miles and estimated a residential population of 120. However, Shell PSR did not indicate a "Yes" next to residences as an identified receptor in their RMP submission, even though Shell PSR did calculate a residential population. The inspection team, using RMP*Comp and Marplot, calculated a radius of 1.1 miles and a residential population of 131. The inspection team's estimates are similar to Shell PSR's estimates.

Shell PSR calculated a flammables ARS radius of 0.43 miles with no receptors identified and no residential population within the radius. Using Marplot, the inspection team calculated that a residential population of 9 lives within a radius of 0.43 miles from the center of the cluster of six spheres within the tank farm. However, it is not clear from Marplot where the boundary of the radius crosses the facility fence line into residential areas. The 0.43 mile radius does reach the Linde and Air Liquide hydrogen plants adjacent to Shell PSR off of South Texas Road, and may reach the Chemtrade facility on North

Texas Road, across from Shell PSR, depending on the center of the release. Therefore, Shell PSR should have indicated major commercial, office, or industrial areas as receptors in the flammables ARS OCA.

The documentation provided by Shell PSR during the inspection indicates the facility may have used Phast to model a pool fire as the flammables ARS OCA (PSR05874-PSR05878). This would contradict the information provided in the Shell PSR RMP submission, which indicates they used the EPA OCA Guidance. The documentation presents some tables and graphs that are labeled with PHAST. However, the documentation is not clear on the modeling methodology used. Based on this information, Shell PSR did not update their April 22, 2015 RMP submission with accurate information for their flammables ARS OCA.

Potential CAA Finding 1: Hazard Assessment, 40 CFR § 68.30:

Requirement found at Subpart B – Hazard Assessment, 40 CFR § 68.30(b): Population shall include residential population. The presence of institutions (schools, hospitals, prisons), parks and recreational areas, and major commercial, office, and industrial buildings shall be noted in the RMP.

- Shell PSR did not indicate major commercial, office, or industrial areas as receptors in their flammables ARS OCA. The inspection team identified neighboring industrial facilities as being within a 0.43 mile radius from each of the six storage spheres, which were identified as the point of release.
    - **Potential CAA Finding 1:** The facility failed to identify major commercial, office, and industrial buildings as receptors in the RMP.

PROCESS SAFETY INFORMATION: 40 CFR § 68.65

Safe Upper and Lower Limits

Shell PSR established an instruction for maintaining Ensure Safe Production (ESP) limits and alarms in Plant Standing Instruction (PSI) PSIE023 – *ESP Limit & Alarm Policy* (PSR04530-PSR04560). Shell PSR uses the following alarm philosophy:

- Normal operating range is bound by high and low target limits. Target limits are indicated by a low priority alarm or alert.
- Safe operating range (within which the process is safe to operate indefinitely) is bound by high and low standard limits. Standard limits are indicated by a high priority alarm.
- Critical limits indicate the point at which an undesired event will occur soon, and are designed to allow enough time for operator to take action before the undesired event occurs. Critical limits are indicated by an emergency priority alarm.

Per PSIE023, the variable table must include the following information for critical and standard limits and target ranges:

- Reason for value
- Boundary (limit) owner
- Potential impact (the consequences of exceeding the limit)
- Inside action
- Outside action
- Boundary name (the equipment constraints used to set the limit)
- Escalation
- Notes

Per PSIE023, adding, removing, or modifying a critical or standard limit (the value of the limit or the limit type, i.e., critical or standard) are managed through the management of change (MOC) process. Correcting, updating, or adding additional information to the variable table are managed outside of the MOC process, using a work process specified in PSIE023.

The inspection team reviewed print-outs from the ESP Variable Table for the following process variables:

- 90PI238 – Pressure in line delivering ammonia to a dilution skid for selective catalytic reduction (SCR) system in RMP-covered process Boiler House/Cogeneration (PSR04656-PSR04661)
- 90LI013 – Liquid level in ammonia tank 90-C009 in RMP-covered process Boiler House/Cogeneration (PSR05751-PSR05757)
- 90PI016 – Pressure in ammonia tank 90-C009 in RMP-covered process Boiler House/Cogeneration (PSR05758-PSR05766)
- 11TI291 – Temperature on reactor effluent inlet to tube-side of exchanger 11E-101B in RMP-covered process HTU #2 (PSR05767-PSR05776)
- 11TI1_7 – Temperature on reactor effluent outlet from tube-side of exchanger 11E-101A in RMP-covered process HTU #2 (PSR05777-PSR05783)

Each variable reviewed included the required information, per PSIE023, as described above. However, the “reason for value” stated for the emergency (critical high) alarm for 90PI016 of 200 psig is: “12% below atmosphere PRV release (250)” (PSR05758-PSR05766). The inspection team confirmed the set pressure of PSV17 and PSV18 is 250 psig (PSR03980). The emergency alarm of 200 psig is not 12% below 250 psig. Rather, 200 psig is 20% below 250 psig. Therefore, Shell PSR failed to ensure the process safety information for safe upper and lower limits is accurate.

<u>Process Flow Diagrams and Material and Energy Balances</u>

The inspection team reviewed process flow diagrams for HTU #2 (PSR05208-PSR05220). These process flow diagrams include material and energy balances (as stream summary tables) for HTU #2. The inspection team did not identify any areas of concern. Note that HTU #2 was revamped in 2005: a reactor and heat exchanger were added. Although, 40 CFR 68.65(d)(1)(vii) only requires material and energy balances for processes built after June 21, 1999, major process revamps after this date may require material and energy balances.

<u>Materials of Construction</u>

The inspection team reviewed corrosion and material diagrams for HTU #2 that Shell PSR provided in response to the inspection team’s request for materials of construction for HTU #2 (PSR05272-PSR05279). The corrosion and material diagrams are process flow diagrams that indicate corrosion loops and materials of construction for piping and process vessels. The inspection team did not identify any areas of concern.

<u>Piping and Instrumentation Diagrams (P&IDs)</u>

The inspection team performed three P&ID field verifications at Shell PSR: 1) the ammonia storage tank (90-C009), which is within the RMP-covered process Boiler House/Cogeneration; 2) a portion of the charge/effluent heat exchangers for HTU #2 (an RMP-covered process); and 3) butane storage sphere TK-102, which is within the RMP-covered process Tank Farm.

Ammonia Storage Tank (90-C009) P&ID Field Verification:

The inspection team field verified P&ID drawing number 90-DA-0640 FR.8, (PSR03980) and had the following findings:

- The inspection team observed that the vapor return line (3”-90-NAH-2002-J312) from the vaporizer (90-P010) to the ammonia storage tank (90-C009) had steam tracing. However, the P&ID did not indicate steam tracing on this line (Photo #1 and Photo #2).
- The inspection team observed a manual valve upstream of the local pressure indicator (PI) on the top of the vaporizer (90-P010). However, the P&ID did not indicate this manual valve.
- The P&ID indicates the vaporizer vapor return line (3”-90-NAH-2002-J312) has a PSV upstream of where the vapor return line connects to the top of the ammonia storage tank (PSV 14). The inspection team observed a manual valve that was car sealed open upstream of PSV 14, but the P&ID does not indicate this manual valve (Photo #3).
- The P&ID indicates that the 2” manual valve closest to the truck connection point on each of the ammonia liquid fill line (2”-90-NAH-2003-J312) and the ammonia vapor return line (2”-90-NAH-2001-J312) are car sealed closed. However, the inspection team did not observe car seals on either of these valves.
- The P&ID indicates an additional truck unloading connection point branching off of the primary ammonia liquid fill line (2”-90-NAH-2003-J312). However, the inspection team observed in the field that this connection point was capped with a local PI assembly with a manual valve, which was not indicated on the P&ID. Additionally, the inspection team observed that the 1” manual valve on the bypass line connecting the truck unloading connection line to the pressure relief line to be car sealed closed. However, the P&ID did not indicate this valve to be car sealed closed (Photo #4).
- The P&ID indicates the ammonia tank has an instrumented level transmitter (LIT 13). However, the inspection team observed that this instrumented level transmitter also had a local level indicator (LI) installed on the tank. The P&ID did not indicate a local LI (Photo #5).
- The P&ID indicates the ammonia tank has a thermowell (TW 13) and local temperature indicator (TI 13) on one of the heels of the tank. However, the inspection team did not identify TW 13 or TI 13 on the tank.
- The inspection team observed two manways installed on the tank: one on one of the heels of the tank (Photo #6) and one on the top of the tank (Photo #7). However, the P&ID does not indicate either of these two manways.
- The P&ID indicates a three-way valve installed on top of the tank, which has flow options to two different pressure safety valves (PSVs): PSV 17 and PSV 18. Per the refinery operator escorting the inspection team, the three-way valve is turned to allow relieving flow to one of the two PSVs at a time. The inspection team observed this three-way valve to be car sealed, but the P&ID does not indicate the valve is car sealed (Photo #8).
- The inspection team observed pressure control valve (PCV) 18 to have steam tracing. However, the P&ID does not indicate that PCV 18 has steam tracing (Photo #9).
- The inspection team observed a bleeder valve on the PCV 18 bypass line. The P&ID does not indicate this bleeder valve (Photo #10).
- The inspection team observed a bleeder valve upstream of PCV 18. The P&ID does not indicate this bleeder valve (Photo #11).
- The P&ID indicates that the ammonia monitoring detectors can trigger a visual alarm (AL 13) and an audible alarm (a horn) (AI 13). However, the refinery operator escorting the inspection team told the inspection team that the ammonia tank only has a visual alarm (a red beacon light) and does not have a horn. The inspection team observed the red beacon light.

HTU #2 – Charge/Effluent Exchangers (11E-101 A/B and E/F) P&ID Field Verification:

The inspection team field verified portions of P&ID drawing numbers 11-DA-008 FR.4 (PSR04583) and 11-DA-008 FR.5 (PSR04584) and had the following findings:

11E-101 E/F

- The inspection team observed an instrumented temperature element (TE 289) and a drain line to a process sewer on the reactor feed immediately upstream of the 11E-101E exchanger. The P&ID for this exchanger (11-DA-008 FR.4; PSR04583) does not indicate this TE or drain line. However, it is possible these items may be on an adjoining P&ID, but the inspection team does not currently have the appropriate P&ID to verify.

11E-101 A/B

- The P&ID (11-DA-008 FR.5; PSR04584) indicates that the 11E-101A reactor charge bypass line, bypassing the flow control valve FV 4, has a local PI. However, the inspection team observed a bleeder valve in place of the local PI (Photo #12).
- The P&ID (11-DA-008 FR.5; PSR04584) indicates that the HP condensate line (2"-11-SC-14-J12) can be connected to a swing ell to connect HP condensate flow into the reactor charge inlet to 11E-101A and the reactor effluent outlet from 11E-101A. However, the inspection team did not observe a swing ell in place; it appeared the swing ell had been disconnected (Photo #13).
- The inspection team observed a bleeder valve on the reactor effluent outlet from 11E-101A (10"-11-OH-25-J64) immediately upstream of the 10" manual valve and spectacle (Photo #14). However, the P&ID (11-DA-008 FR.5; PSR04584) does not indicate this bleeder valve.
- The P&ID (11-DA-008 FR.5; PSR04584) indicates the 2" manual valve on the relief line to the flare from the reactor effluent outlet from 11E-101A (2"-11-VF-20-J64) is blinded. However, the inspection team did not observe a blind on this line (Photo #15).
- The P&ID (11-DA-008 FR.5; PSR04584) indicates the HP condensate line (2"-11-SC-14-J12) can drain into a process sewer. However, the inspection team observed this process sewer drain to be closed-off with a cap (Photo #16).
- The inspection team observed a bleeder valve downstream of the 2" manual valve on the relief line to the flare from the reactor charge inlet to 11E-101A (2"-11-VF-16-J64) (Photo #17). However, the P&ID (11-DA-008 FR.5; PSR04584) does not indicate this bleeder valve.

Butane Storage Sphere (TK-102) P&ID Field Verification:

The inspection team field verified portions of P&ID drawing number 21-DA-0250 FR.7 (PSR03983) of mixed butane storage sphere TK-102. The inspection team had the following findings:

- The inspection team observed a manway at the bottom of TK-102 (Photo #18). However, the P&ID does not indicate this manway.
- The inspection team observed a bleeder valve on each of the two pressure relief lines at the top of TK-102 for pressure safety valves (PSVs) 456 and 457: both bleeder valves were upstream of the PSVs and downstream of the 6" car-sealed open valves (Photo #19). However, the P&ID does not indicate these two bleeder valves on the relief lines.
- The inspection team observed a bleeder valve on line 4"-21-0-159-J050B, in-between the 4" car-sealed open valve and the 4" check valve (Photo #20). However, the P&ID does not indicate this bleeder valve.

Electrical Classification

The inspection team reviewed the electrical classification drawing for Electrical Area Classification Block 57, which includes the RMP-covered processes HTU #2 and CRU #2 (PSR05887). The inspection team did not observe any areas of concern from this review.

Relief System Design and Design Basis

The inspection team reviewed pressure safety valve (PSV) design documentation for ammonia storage tank 90-C009 in RMP-covered process Boiler House/Cogeneration (PSR05888-PSR05921). The inspection team did not identify any areas of concern.

Inspection of Alkylation Unit

Brian Ricks, the USW PSM Representative, introduced the inspection team to an operator in the RMP-covered process Alky 1. The operator, Jim Caddell, brought to EPA's attention several concerns.

Alky Gas Separator

The operator expressed concern with a gas separator within Alky 1. This gas separator (5JC-94) separates light hydrocarbons (C3, C4, and light gasoline) from oily liquid bottoms. The oily liquid is discharged into a process sewer (Photo #21). However, the operator stated that the gas separation is not adequate, and gases flash in the sewer pump, creating a potential lower explosive limit (LEL) atmosphere. The inspection team visited this gas separator and observed the discharge of watery liquid into the process sewer. Mike Osborne, the Process Specialist for Alky escorting the inspection team, said there is a sensor that detects the presence of hydrocarbon in the water outlet from the gas separator.

Alky Spent Acid Tanks

The operator expressed concern with the spent acid tanks within Alky 1 (TK-402 and TK-403). These spent acid tanks are fixed-roof tanks with a nitrogen blanket (Photo #22, Photo #23). The tanks were installed in 1958 as part of the original construction of the refinery (PSR06959-PSR06960). The tanks receive spent acid from the alkylation process, which contains hydrocarbons. The nitrogen blanket is used to maintain an inert atmosphere as spent acid pumps in and out of the tank. The vent on each tank (Photo #24) feeds into an oil bath at grade for each tank (Photo #25, Photo #26). The oil bath provides approximately 1 psig of backpressure. When the tank pressure exceeds this backpressure, hydrocarbon gases vent out of the oil bath at grade. The operator stated that the tanks continuously vent hydrocarbon gases, and the operators find this condition hazardous. The inspection team visited the spent acid tanks, and in particular inspected the PRV and vent oil bath at TK-403 (PRV 5035). The inspection team observed a leaker tag on PRV 5035 that indicated a reading of 50,000 ppm, although details of this reading were not described (Photo #27). The leaker tag was dated August 4, 2015. While taking photographs of, and in close proximity to, PRV 5035, the inspection team smelled a strong hydrocarbon odor causing an inspector to briefly choke on the inhaled vapors.

The inspection team reviewed process flow diagrams of Alky 1 (PSR05922 and PSR06201) and confirmed the connection between the spent acid tanks and the alkylation process.

The inspection team identified the following OSHA requirement, 29 CFR 1910.106 – Flammable Liquids, regarding vent pipes from tanks storing Category 1 or 2 flammable liquids or Category 3 flammable liquids with a flash point below 100 °F[1]:

> 29 CFR 1910.106(b)(2)(vi)(b) (Tank storage, Installation of outside aboveground tanks, Vent piping for aboveground tanks):
> "Where vent pipe outlets for tanks storing Category 1 or 2 flammable liquids, or Category 3 flammable liquids with a flashpoint below 100 °F (37.8 °C), are adjacent to buildings or public ways, they shall be located so that the vapors are released at a safe point outside of buildings and not less than 12 feet above the adjacent ground level. In order to aid their dispersion, vapors shall be discharged upward or horizontally away from closely adjacent walls. Vent outlets shall be located so that flammable vapors will not be trapped by eaves or other obstructions and shall be at least five feet from building openings."

The vent pipe discharges for Tanks TK-402 and TK-403 are located in areas where operators perform duties and the vent pipes' discharge point is at grade. Therefore, they are less than 12 feet above the adjacent ground level. In addition, the vent pipes' discharges each have a rain cap, and the vapors discharge horizontally. Additionally, the vent pipe discharges are located inside of the tank berm. The location and configuration of the discharges are likely to result in poorly dispersed hydrocarbon vapors that could result in trapped vapors.

While the aforementioned OSHA requirement is specific to tanks that store flammable liquids with a flash point below 100 °F, the Shell PSR spent acid tanks, TK-402 and TK-403, contain light hydrocarbon materials within the spent acid phase based on statements made by the Alky 1 operator. He stated the tanks continuously vent hydrocarbon gases. Although it cannot be confirmed based on available information at this time, it is likely that the hydrocarbons within TK-402 and TK-403 have a flash point below 100 °F. As a point of reference, n-decane has a flash point of approximately 115 °F. Generally speaking, hydrocarbons lighter than n-decane have flash points less than 100 °F. Typically, hydrocarbons present in an alkylation unit include alkylate product (a gasoline material, typically a C8), isobutane, propylene, and may also include some n-butane, butylene, and propane.

Additionally, the inspection team identified the following industry standards that provide guidance on the location of vent discharge piping:

- API 2000 – Venting Atmospheric and Low-pressure Storage Tanks; Sixth Edition, November 2009. Section 4.7.2 – Discharge Piping states: "Discharge piping from the relief devices or common discharge headers shall comply with the following. a) It shall lead to a safe location. A number of standards (e.g. API 500, TRbF 20, NFPA 30, IEC 60079-10) provide considerations for determining safe discharge of storage tank relief systems."
- NFPA 30 – Flammable and Combustible Liquids Code; 2015 Edition. Section 27.8.1.1, under Vent Piping for Aboveground Storage Tanks, states the following: "Where the outlets of vent pipes for tanks storing Class I liquids are adjacent to buildings or public ways, they shall be located so that vapors are released at a safe point outside of buildings and not less than 12 ft (3.6 m) above the adjacent ground level."

<u>Potential CAA Findings 2 to 4: Process Safety Information, 40 CFR § 68.65:</u>

[1] 29 CFR 1910.106 defines the following: Category 1 flammable liquids have a flash point below 73.4 °F and a boiling point at or below 95 °F. Category 2 flammable liquids have a flash point below 73.4 °F and a boiling point above 95 °F. Category 3 flammable liquids have a flash point at or above 73.4 °F and at or below 140 °F.

Requirement found at Subpart D – Prevention Program, 40 CFR § 68.65(c)(1)(iv): "Information concerning the technology of the process shall include at least the following: Safe upper and lower limits for such items as temperatures, pressures, flows or compositions;…"

- The "reason for value" explanation of the emergency (critical high) alarm for 90PI016 is inaccurate for the value presented in the alarm table (PSR05757-PSR05766). The "reason for value" states the alarm is set at 12% below the PRV set pressure of 250 psig. However, the alarm is actually set at 20% below the PRV set pressure.

    - **Potential CAA Finding 2:** The facility failed to update and ensure that the process safety information for safe upper and lower limits were accurate.

Requirement found at Subpart D – Prevention Program, 40 CFR § 68.65(d)(1)(ii): Information pertaining to the equipment in the process shall include: (ii) Piping and instrument diagrams (P&ID's)

- The inspection team observed several discrepancies between instrumentation, piping, and valve configurations in the field that were not accurately identified on P&ID drawing numbers:
    - 90-DA-0640 FR.8 (Ammonia Storage Tank, 90-C009) (PSR03980);
    - 11-DA-008 FR.4 (HTU #2 Charge/Effluent Exchangers) (PSR04583);
    - 11-DA-008 FR.5 (HTU #2 Charge/Effluent Exchangers) (PSR04584); and
    - 21-DA-0250 FR.7 (Butane Storage Sphere, TK-102) (PSR03983).

    - **Potential CAA Finding 3:** The facility failed to update and ensure that process P&IDs accurately reflected the design of a covered process as installed in the field.

Requirement found at Subpart D – Prevention Program, 40 CFR § 68.65(d)(2): "The owner or operator shall document that equipment complies with recognized and generally accepted good engineering practices."

- The inspection team observed that the alkylation spent acid tanks have pressure relief valves that vent vapors at the grade of the tanks and discharge the vapors horizontally inside of the tank berm (Photos #22, #23, #24, #25, #26, #27; PSR05922 and PSR06201). This location and manner of vent discharging poses a potentially hazardous condition to workers through inhalation exposure or a potential atmosphere above the LEL (29 CFR 1910.106(b)(2)(vi)(b); API 2000, November 2009; NFPA 30, 2015 Edition).

    - **Potential CAA Finding 4:** The facility failed to ensure that equipment complies with recognized and generally accepted good engineering practices and is designed and operating in a safe manner.

PROCESS HAZARD ANALYSIS: 40 CFR § 68.67

The inspection team interviewed Casey Smith, a process safety engineer and Process Hazard Analysis (PHA) and Hazards and Effects Management Program (HEMP) Focal Point at Shell PSR. Mr. Smith facilitates PHAs for processes in the west and south sides of the refinery. A PHA typically takes three to five weeks. PHAs use the hazard and operability (HazOp) study methodology, although some may use What-If if they have not been revalidated recently. For example, Mr. Smith stated that previously Shell PSR used the What-If methodology for the receiving, pumping, and shipping (RP&S) piping PHAs, but he revalidated these PHAs using HazOp. Shell PSR uses the PrimaTech™ PHA Works software to capture nodes, deviations, parameters, and severity and likelihood rankings. Shell PSR uses Fountain to track recommendations and due dates. Mr. Smith said a Fountain focal employee will manage the target dates of recommendations and send out a list of open items twice a month to recommendation owners. Mr. Smith said that he himself audits recommendations to ensure they are closed out adequately. He targets performing audits in Fountain quarterly. There is also a USW process safety representative who can review PHA recommendation close-outs. Currently this representative at Shell PSR is Carlos Alonzo.

At the conclusion of a PHA, Shell PSR conducts a “management handshake.” Shell PSR provided the inspection team with a document outlining guidance for managing PHA recommendations, which is a part of the management handshake (PSR04812-PSR04818). This document provides guidance on setting due dates for recommendations and setting the approvals needed to change recommendation due dates. The document provides a DSM Prioritization Tool, which is a matrix that provides guidance on setting recommendation due dates based on the identified hazard’s criticality and the constraint to complete the recommendation. The guidance includes the necessary approval to change a recommendation due date. The management position needed for approval is a function of the recommendation’s risk assessment matrix rating.

The inspection team reviewed the Shell PSR *Qualitative Hazard and Operability Study for Vacuum Pipe Still (VPS) or Crude Unit #1; PHA – Final; July 2015* (PSR00573-PSR00769). Shell PSR used the hazard and operability (HazOp) study methodology to complete this PHA revalidation.

The inspection team did not identify any areas of concern.

OPERATING PROCEDURES: 40 CFR § 68.69

Shell PSR has established the facility policy *PSIA063 – Operating Procedures* (PSR04512-PSR04529) to provide procedures for creating, reviewing, approving, controlling, using, and updating operating procedures. PSIA063 states that all operating procedures shall be certified annually that they are current and accurate. Operating procedure owners are required to certify in writing on May 26th of each year that the operating procedures are current and accurate. The Shell PSR Learning and Development Department coordinates, tracks, and maintains the annual certifications. The PSIA063 annual certification requirement is intended to meet the requirements specified in 40 CFR 68.69(c).

PSIA063 requires operating procedures for the following operating phases:
- Initial startup
- Normal operations
- Emergency shutdown
- Emergency operations
- Normal shutdown
- Instrumented protective function
- Safety systems
- Turnaround procedures (including startup after a turnaround)
- Startup after emergency shutdown
- Unit standing orders
- Safe work practices

The above operating phases are intended to meet the requirements specified in 40 CFR 68.69(a)(1).

PSIA063 requires that operating procedures direct the user to the ESP Variable Table database for parameters such as safe upper and lower limits, consequences of deviation, and steps to correct or avoid deviations. This requirement is intended to meet the requirements specified in 40 CFR 68.69(a)(2).

PSIA063 requires that operating procedures describe health, safety, and environment considerations and personal protective equipment requirements. It also requires that operating procedures direct the user to the Material Safety Data Sheet (MSDS) database for information including:

- Properties of, and hazards presented by, the chemicals used in the process;
- Precautions necessary to prevent exposure, including engineering controls, administrative controls, and personal protective equipment;
- Control measures to be taken if physical contact or airborne exposure occurs;
- Quality control for raw materials and control of hazardous chemical inventory levels; and
- Any special or unique hazards.

The above requirements are intended to meet the requirements of 40 CFR 68.69(a)(3).

PSIA063 requires that new or revised operating procedures are managed through Shell PSR's MOC system.

PSIA063 requires that the most current and up-to-date copy (controlled copy) of operating procedures be maintained in Shell PSR's electronic document management system (EDOC), with additional copies maintained in the control room and operating shelters. This requirement is intended to meet the requirements of 40 CFR 68.69(b).

The emergency (critical high) alarm for 90PI238 (the pressure in the ammonia line delivered to the dilution skid for SCR system unit 2) indicates the following operator actions (PSR04656-PSR04661):

- "Inside Action: Close 90HS17; If closing 90HS17 does not relieve pressure, assume PRV and/or bypass are open and relieving NH3 to atmosphere – activate ERT immediately."
- "Outside Action: Check for potential failure of pressure regulator; open bypass to maintain pressure at local indicator of 20 psig; an operator must be stationed at the bypass while open in order to be able to respond if necessary."

The inside and outside operator actions appear to contradict each other. The inside action states that, if closing valve 90HS17 does not resolve the high pressure, then the console operator is to assume the PRV and/or bypass are open and relieving to the atmosphere and to activate the ERT (inspection team assumes this stands for emergency response team). However, the outside action states that the outside operator is to open the bypass to maintain an ammonia line pressure of 20 psig if the pressure regulator (PCV18) failed. The outside operator is to remain stationed at the bypass. Having the outside operator open and stay stationed at the bypass appears to contradict the console operator assuming the PRV and/or bypass are open and relieving and activate the ERT.

The inspection team visited the Shell PSR control room and briefly interviewed console operator Robin Fakkema (who works on the console that covers the HTU #2 and #3, CRU, and hydrogen system). The inspection team observed an electronic and hardcopy version of the emergency shutdown procedure for HTU #2 in the control room. The inspection team confirmed the revision date and version number of the hardcopy and electronic versions of the procedure matched.

After the inspection, EPA requested additional documents pertaining to Shell PSR's operation of the ammonia storage tank (90-C009) in a request for information dated March 29, 2016. Shell PSR submitted the following operating procedures under a cover letter dated May 2, 2016:

- Ammonia Leak procedure; 90COGEO002; dated April 17, 2014 (Bates # PSR06981-PSR06982);
- Ammonia Tank Shutdown procedure; 90COGTO026; dated August 2, 2012 (Bates # PSR06977-PSR06980);
- Ammonia Tank Shutdown procedure; 90COGTO026; dated January 13, 2016 (Bates # PSR06973-PSR06976);

- Ammonia Unloading procedure; 90COGNO030; dated January 30, 2014 (Bates # PSR06967-PSR06972);
- Ammonia Unloading procedure; 90COGNO030; dated September 8, 2015 (Bates # PSR06961-PSR06966);
- PIS Mitigation Plan; 90PIS10A Cogen Ammonia Area Monitor with Auto Deluge and Ammonia Cutoff; 90COGPIS041; dated August 29, 2014 (Bates # PSR06983-PSR06984).

Ammonia Tank Shutdown Procedure

The inspection team reviewed the Ammonia Tank Shutdown procedure, 90COGTO026, dated August 2, 2012, which was in effect at the time of the inspection (Bates # PSR06977-PSR06980). Under the section Materials/Equipment, the procedure states "there are no special materials or equipment required for this procedure." However, after step 3.3, the warning box states "ammonia can cause respiratory distress, chemical burns, and death. Use proper PPE including supplied air when venting ammonia to the atmosphere." This procedure does not describe the proper PPE, including the supplied air respirators, required to have available and for the operators to don when performing this procedure.

Step 2.7 of this procedure instructs the operator to open the 2-inch block valve on the unloading line to pressurize the line with nitrogen. Step 2.8 then states to slowly throttle the 2-inch block valve on the 2-inch ammonia fill line to begin pressurizing the ammonia tank with nitrogen. However, the procedure does not provide distinction between these two 2-inch block valves to adequately inform the operator which valve to open in step 2.7 and which valve to slowly throttle in step 2.8. The procedure also refers to the same line differently in these two steps ("unloading line" in step 2.7 and "ammonia fill line" in step 2.8). Therefore, this procedure does not provide clear instructions for safely conducting the ammonia tank shutdown.

Ammonia Unloading Procedure

The inspection team reviewed the Ammonia Unloading procedure, 90COGNO030, dated January 30, 2014, which was in effect at the time of the inspection (Bates # PSR06967-PSR06972). Under the section Materials/Equipment, the procedure lists PPE, including two self-contained breathing apparatuses (SCBAs), that "must be at the site prior to and during transfer." Step 1.1 instructs the operator to verify that all correct safety equipment is accessible, and step 6.1 instructs the operator to verify that the truck driver is wearing the proper PPE. However, the procedure does not state which PPE the operators and truck driver must don when performing the procedure.

The ammonia tank shutdown procedure (Bates # PSR06977-PSR06980) instructs the operator, at step 2.4, to "ensure that the 1-inch vent on the unloading line is closed." Presumably, this step is to ensure that ammonia cannot bypass PSV15 and vent to the atmosphere. However, the ammonia unloading procedure (Bates # PSR06967-PSR06972) does not instruct the operator to ensure that the 1-inch vent on the unloading line is closed to prevent ammonia from venting to the atmosphere during truck unloading.

Potential CAA Finding 5-6: Operating Procedures, 40 CFR § 68.69:

Requirement found at Subpart D – Prevention Program, 40 CFR § 68.69(a): "The owner or operator shall develop and implement written operating procedures that provide clear instructions for safely conducting activities involved in each covered process consistent with the process safety information and shall address at least the following elements…"

- The operator actions for an emergency (critical high) alarm for 90PI238 direct the outside operator to open and stay stationed at the PCV18 bypass, which may contradict the console operator actions and result in an unsafe situation if the PRVs are relieving.
- The ammonia tank shutdown procedure (Bates # PSR06977-PSR06980) does not provide distinction among the 2-inch block valves on the unloading line/ammonia fill line to provide clear instructions to the operators when opening these valves during steps 2.7 and 2.8.
- The ammonia unloading procedure (Bates # PSR06967-PSR06972) does not instruct the operator to ensure that the 1-inch vent on the unloading line is closed to prevent ammonia from venting to the atmosphere during truck unloading.

    - **Potential CAA Finding 5:** The facility failed to develop and implement written operating procedures that provide clear instructions for safely conducting activities in each covered process.

Requirement found at Subpart D – Prevention Program, 40 CFR § 68.69(a)(3)(ii): "The owner or operator shall develop and implement written operating procedures that provide clear instructions for safely conducting activities involved in each covered process consistent with the process safety information and shall address at least the following elements…Safety and health considerations:…Precautions necessary to prevent exposure, including engineering controls, administrative controls, and personal protective equipment."

- The ammonia tank shutdown procedure (Bates # PSR06977-PSR06980) does not describe the proper PPE, including the supplied air respirators, required to have available and for the operators to don when performing this procedure.
- The ammonia unloading procedure (Bates # PSR06967-PSR06972) does not state which PPE the operators and truck driver must don when performing the procedure.

    - **Potential CAA Finding 6:** The facility failed to develop and implement written operating procedures that address the personal protective equipment necessary to prevent exposure.

<u>TRAINING: 40 CFR § 68.71</u>

Shell PSR has established the Learning and Development (L&D) Departmental Policy *LDPOL001 – Operator Training* (PSR04825-PSR04846) to maintain a consistent training philosophy and practice. This policy only applies to production department employees across all operating units. Operator initial training generally includes new employee orientation; health, safety, security & environmental (HSSE) training; operator fundamentals training; process unit training; and job specific training. LDPOL001 requires revalidation/requalification training at least every three years or more often if necessary.

The inspection team interviewed the Shell PSR USW PSM Representative, Brian Ricks, and discussed aspects of Shell PSR's training program. Mr. Ricks stated that Shell PSR's hazardous waste operations (HAZWOPER) annual refresher training used to be eight hours of classroom training. Earlier this year (around March 2015), the refinery changed the HAZWOPER annual refresher training to a computer-based training. The refinery's HAZMAT team used to use the 8-hr HAZWOPER refresher training as part of their refresher training. However, the HAZMAT team is not able to use the computer-based training and has been trying to determine an alternate 8-hr HAZWOPER refresher training option. Mr. Ricks expressed concern that the new computerized 8-hr HAZWOPER refresher training lacks refinery specifics.

<u>MECHANICAL INTEGRITY: 40 CFR § 68.73 [NEIC]</u>

ERG did not evaluate this RMP element.

MANAGEMENT OF CHANGE AND PRE-STARTUP SAFETY REVIEW: 40 CFR §§ 68.75 AND 68.77 [NEIC]

ERG did not evaluate these RMP elements.

COMPLIANCE AUDITS: 40 CFR § 68.79 [REGION 10]

ERG did not evaluate this RMP element.

INCIDENT INVESTIGATION: 40 CFR § 68.81 [REGION 10]

ERG did not evaluate this RMP element.

EMPLOYEE PARTICIPATION: 40 CFR § 68.83 [REGION 10]

ERG did not evaluate this RMP element.

HOT WORK PERMIT: 40 CFR § 68.85 [NEIC]

ERG did not evaluate this RMP element.

CONTRACTORS: 40 CFR § 68.87 [NEIC]

ERG did not evaluate this RMP element.

EMERGENCY RESPONSE: 40 CFR § 68.95 [NEIC]

ERG did not evaluate this RMP element.

SUMMARY OF FINDINGS

CAA 112(r)(7), 40 CFR Part 68: Summary of RMP Findings		
CAA Finding No.	***Description***	***Citation***
1	The facility failed to identify major commercial, office, and industrial buildings as receptors in the RMP.	40 CFR § 68.30(b)
2	The facility failed to update and ensure that the process safety information for safe upper and lower limits were accurate.	40 CFR § 68.65(c)(1)(iv)
3	The facility failed to update and ensure that process P&IDs accurately reflected the design of a covered process as installed in the field.	40 CFR § 68.65(d)(1)(ii)
4	The facility failed to ensure that equipment complies with recognized and generally accepted good engineering practices and is designed and operating in a safe manner.	40 CFR § 68.65(d)(2)
5	The facility failed to develop and implement written operating procedures that provide clear instructions for safely conducting activities in each covered process.	40 CFR § 68.69(a)
6	The facility failed to develop and implement written operating procedures that address the personal protective equipment necessary to prevent exposure.	40 CFR § 68.69(a)(3)(ii)

8/24/2016
Report Author (date)

11/30/16
Report Reviewer (date)